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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026

ORDER MODIFYING DECISION 18-10-019 AND DENYING REHEARING OF THE DECISION, AS MODIFIED

I. SUMMARY

In this Order, we dispose of the applications for rehearing of Decision (D.) 18-10-019 (or "Decision"),[1] filed by (1) Shell Energy North America (US), L.P. ("Shell"); (2) California Community Choice Association, CleanPowerSF, and Solana Energy Alliance (collectively "CalCCA"); (3) California Large Energy Consumers Association and Direct Access Customer Coalition (collectively "CLECA"); (4) Protect our Communities Foundation and Utility Consumers' Action Network (collectively "POC"); and (5) Peninsula Clean Energy, Marin Clean Energy, and Sonoma Clean Power (collectively "PCE").

In D.18-10-019, we adopted revised inputs to the market price benchmark ("MPB") used to calculate the Power Charge Indifference Adjustment ("PCIA"). The PCIA calculation includes a Brown Power Index, a Renewable Procurement Standard ("RPS") Adder and a Resource Adequacy ("RA") Adder. We determined that the Brown Power Index would continue to be calculated using the methodology adopted in D.06-07-030. However, we revised the RPS Adder and RA Adder to produce more accurate estimates. We also adopted an annual true-up mechanism and a PCIA cap. We

[1] Unless otherwise noted, citations to Commission decisions issued since July 1, 2000 are to the official pdf versions, which are available on the Commission's website at: http://docs.cpuc.ca.gov/DecisionsSearchForm.aspx.

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opened a second phase to develop and consider proposals regarding portfolio optimization and cost reduction.

Shell argues, in its application for rehearing, the following: (1) the Commission does not have the statutory authority to compel electric service providers ("ESPs") to disclose prices for the purpose of establishing a market price benchmark; and (2) the Commission failed to provide the requisite due process when it established new transaction reporting requirements for ESPs.

CalCCA's rehearing application alleges: (1) the Commission erred by including utility-owned generation ("UOG") costs in the PCIA charged to Community Choice Aggregation ("CCA") departing load customers; (2) the Decision causes an unlawful cost shift by failing to reduce the net PCIA portfolio costs by the value of any benefits that remain with bundled service customer as statutorily required; and (3) the Commission violated Public Utilities Code section 366.2(f)(2)[2] because it caused a cost shift by including costs in the PCIA that were avoidable or that were not attributable to departing load customers.

CLECA's rehearing application asserts: (1) the Decision's findings are not support by the record, and (2) the Decision lacks adequate findings of fact.

POC's rehearing application argues D.18-10-019 errs by: (1) making departing load customers indefinitely liable for costs of UOG; (2) placing a cap on the PCIA that fails to protect the economic viability of CCAs; (3) illegally shifting resource costs to departing customers by failing to credit them for all the benefits of those resources; (4) impermissibly assigning avoidable electricity procurement costs to departing customers; and (5) refusing to consider Independent Evaluator and Procurement Review Group Reform and subordinating securitization proposals. POC also requests a stay of D.18-10-019, oral argument, and Commission compliance with section 311.5.

[2] Subsequent section references are to the Public Utilities Code, unless otherwise noted.

PCE's rehearing application asserts: (1) the Commission failed to meet its statutory duty to set the new PCIA based on a factual and legal determination that Investor Owned Utilities ("IOU") incurred legitimately unavoidable costs and took all reasonable steps to minimize above-market costs; and (2) the Decision fails to comply with the requirements set forth in sections 365.2 and 366.2(f)(2), including in the PCIA costs that are not attributable to departing load customers. PCE also states that it supports the Application for Rehearing filed by CalCCA.

Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("Edison"), and San Diego Gas & Electric Company ("SDG&E") filed a joint response and The Utility Reform Network ("TURN") and the Coalition of California Utility Employees each filed a separate response opposing the rehearing applications. CLECA filed a response opposing CalCCA's assertion that pre-2009 vintage Direct Access ("DA") customers must be addressed in this proceeding. Commercial Energy of California filed a response supporting CLECA's rehearing application.

We have carefully considered the arguments raised in the applications for rehearing, and do not find grounds to grant rehearing. We modify D.18-10-019, as discussed below, to correct some citations, to add two conclusions of law, and to clarify our statutory authority to require reporting information of ESPs. Rehearing of D.18-10-019, as modified, is denied.

II. DISCUSSION

A. The adopted transaction reporting requirements are lawful.

In connection with adopting the revised PCIA calculation methodology, we adopted new transaction reporting requirements for all Load Serving Entities ("LSE"), including CCAs and ESPs, to ensure that the market price benchmarks for resource adequacy products and renewable energy reflect actual market prices. We required all LSEs to submit annually to the Energy Division the following contract information: seller name, execution date, contract price ($/MWh), term length of contract, capacity (MW), associated Net Quantifying Capacity, annual expected generation (MWh/year), and expected generation for the forecast year.[3] (D.18-10-019 at p. 160 [Ordering Paragraph 5].)

Shell argues that D.18-10-019 is unlawful because we do not have the statutory authority to compel ESPs to disclose contract prices for the purpose of establishing RA and RPS market price benchmarks. Although not disputing our statutory authority to require ESPs to produce documentation to demonstrate that they have complied with statutory RA and RPS procurement requirements, Shell contends this authority does not extend to using ESP price information to develop market price benchmarks. (Shell Rehg. App. at pp. 4 & 6.) Shell also contends that we wrongfully justified our need for the price information on our statutory obligation to maintain public health and safety and assure adequate service, and on our jurisdiction over IOUs. (Shell Rehg. App. at pp. 2, 6, & 7.)

Upon review, we realize that we have not sufficiently explained the full basis for our jurisdiction to require transaction reporting requirements. Section 380(b)(1) is not the sole basis of our authority to require the transaction reporting requirements. Section 701 provides us sufficient jurisdiction to require the contract information. Section 701 provides us the authority to "do all things necessary and convenient in the exercise of [our] power and jurisdiction to supervise and regulate every public utility." Our authority under section 701 "is not expressly limited to actions against public utilities." (*PG&E Corp v. Public Utilities Com*. (2004) 118 Cal.App.4th 1174, 1198.) We may exercise limited jurisdiction over nonpublic utilities if our action is cognate and germane to utility regulation. (*Id* at. p. 1201 ["*the PUC's exercise of limited jurisdiction over the holding companies is cognate and germane to its regulation of a public utility*"].)

Requiring ESPs to provide contract information is clearly cognate and germane to utility regulation as it specifically relates to our statutory duty to ensure that

[3] The submitted information is subject to the Commission's confidentiality rules. (D.18-10-019 at pp. 78-79.)

there is no cost shifting between bundled retail customers of the electrical corporations and bundled retail customers who elect to receive service from other providers. (Pub. Util. Code, §§ 365.2 & 366.3.) As we explained in D.18-10-019, contract price information is necessary to accurately set the PCIA rate, which is used to ensure electric customers of IOUs that depart from IOU service and receive their electricity from a non-IOU provider, remain responsible for costs previously incurred on their behalf by the IOUs. The contract price information will be used to calculate inputs to the PCIA calculation, which will make them more accurate. (D.18-10-019 at pp. 153, 154, 156, & 160 [Findings of Fact 3, 4, & 6; Conclusion of Law 5; & Ordering Paragraph 5].)

We have modified D.18-10-019 in the ordering paragraphs below to clarify our jurisdiction to require the reporting information of the ESPs to prevent cost shifting between bundled retail customers and departing load customers as statutorily required.

Shell next argues that we improperly failed to consider less intrusive means of obtaining market price information. (Shell Rehg. App. at p. 4.) Shell contends that we dismissed other proposals without any meaningful analysis or discussion. (Shell Rehg. App. at p. 4.)

Shell does not cite any law or decision that requires our decisions to contain an analysis or discussion of every alternative raised by a party. Nor does Shell cite any authority that requires us to consider less burdensome alternatives when meeting our statutory duty to ensure there is no cost shifting. Section 701 authorizes us to do all things "necessary and convenient" in the exercise of our power and jurisdiction. Moreover, as we stated in D.18-19-019, we "reviewed the in-depth analysis provided by parties and evaluated the merits of the proposals before us within the context of the guiding principles established in the Scoping Memo." (D.18-19-019 at p. 72.) We determined that we were "not persuaded that any of the alternatives proposed represented a better capacity benchmark than the RA Report." (D.18-19-019 at p. 152.)

Finally, Shell argues we failed to provide the requisite due process before adopting the new transaction reporting requirements for ESPs. Shell contends that notice of the new transaction reporting requirement was not sufficient because the Order

Instituting Rulemaking and the scoping memo did not mention such requirements. (Shell Rehg. App. at p. 13.) Shell cites to *Southern California Edison Co. v. Public Utilities Com.* (*"Edison"*) (2006) 140 Cal.App.4th 1085, 1106 to support its position. This argument has no merit.

It is well established that due process requires "adequate notice" and an opportunity to be heard. "Due process as to the commission's initial action is provided by the requirement of adequate notice to a party affected and an opportunity to be heard before a valid order can be made." (*People v. Western Airlines, Inc*. (1954) 42 Cal.2d 621, 632.)

Here, Shell and other parties had notice that we might consider the reporting requirements and had an opportunity to be heard before we adopted the requirements. The scoping memo provided notice that the proceeding would review and possibly modify the current PCIA methodology including inputs and alternative methods.[4] (Scoping Memo at p. 8.) In its opening testimony on PCIA modifications, TURN recommended that RA prices and renewable power be based on actual reported purchase and sales prices of IOU, CCA, and ESP transactions. (Exhibit TURN-1 at p. 9.) TURN recommended that the Commission establish new transaction reporting requirements for CCAs and ESPs to calculate the Market Price Benchmark components. (Exhibit TURN-1 at p. 9.) TURN's proposal is encompassed within the scoping memo issues. TURN's brief and reply brief discussed its recommendation. (TURN brief at pp. 8-12, TURN reply brief at pp. 7-8.) Shell had an opportunity to cross-examine TURN's witness and to comment on the proposal in its briefs. Thus, Shell had reasonable notice that we could and might consider this proposal. Once the proposed decision and alternate were issued adopting TURN's proposal, Shell had an opportunity to provide comments

[4] Section 1701.1(b) requires Scoping Memos to include the issues to be addressed in the proceeding but does not require it to list all possible outcomes to a proceeding.

on the reporting requirements. Thus, Shell had sufficient notice and opportunity to be heard prior to our adoption of the reporting requirements.

Shell's cite to *Edison* is not on point. In *Edison*, the Administrative Law Judge ("ALJ") amended the scope of the issues in the proceeding to include new proposals and then provided parties only three days to comment on the new proposals. The Court found that the Commission violated its rules by considering new issues and that three business days was not sufficient time for parties to respond to the new proposals, and thus, was prejudicial. Here, no new issues were added to the proceeding. TURN's proposal was encompassed within the scoping memo issues and parties had sufficient notice and opportunity to be heard on the issues.

B. The Decision did not err by including utility-owned generation costs in the PCIA charged to CCA departing load customers.

CalCCA alleges D.18-10-019 erred by including utility-owned generation costs in the PCIA charged to CCA departing load customers. (CalCCA Rehg. App. at pp. 3-18.) CalCCA contends that section 366.2(f) establishes an exclusive list of PCIA-eligible costs and that pre-2002 fossil-fueled UOG ("Legacy UOG") and post-2002 fossil-fueled UOG ("Post-2002 UOG") are not listed in section 366.2 and thus cannot be recovered from CCA customers. (CalCCA Rehg. App. at pp. 3-18.) POC makes similar arguments. (POC Rehg. App. at pp. 9-22.) CalCCA and POC assert that it was legal error for the Decision to determine that section 366.2 was not an exclusive list of PCIA eligible costs.

CalCCA and POC raise the same arguments they raised during the proceeding, which we considered and rejected. We do not read section 366.2 to be an exclusive list of PCIA eligible costs. (D.18-10-019 at p. 52.) As we explained, both Assembly Bill ("AB") 117 and Senate Bill ("SB") 350 require us to prevent cost shifts between customers as a result of customer departure. (D.18-10-019 at p. 51.) We determined that CalCCA's reading would wrongly override the Legislature's direction to prevent any cost shifting. (D.18-10-019 at p. 52.) We further determined that such reading would wrongly subordinate a later-in-time statute to an earlier-in-time statute. (D.18-10-019 at p. 52.) We concluded that including Legacy UOG costs in the PCIA was consistent with both AB 117 and SB 350. (D.18-10-019 at p. 157 [Conclusion of Law 12].)

CalCCA and POC contend that only their reading harmonizes the statutory provisions. CalCCA argues that the cost shifting prohibition in section 366.2 must be read to apply only to the specific costs listed in section 366.2(f). CalCCA maintains that if the Legislature wanted to include UOG costs it would have listed them because it was aware of the existence of such costs. (CalCCA Rehg. App. at p. 6.)

The fundamental task in statutory interpretation is to determine the intent of the Legislature. (Cal. Proc. Code, § 1859; (See *City of Santa Cruz v. Municipal Court* (1989) 49 Cal.3d 74, 90.) The Commission "must ascertain legislative intent so as to effectuate a law's purpose." (See *Neumarkel v. Allard* (1985) 163 Cal.App.3d 457, 461, citing *Select Base Materials v. Board of Equal* (1959) 51 Cal.2d 640, 645.) The Legislature made its intent clear when enacting AB 117 stating, "It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers."[5] (Pub. Util. Code § 366.2(d)(1).) If, as CalCCA argues, the Legislature had listed all recoverable costs, there would be no need to include additional cost shifting language in section 366.2(a)(4) and 366.2(d)(1). Reading the list of costs as those that must be recovered rather than as an exclusive list, harmonizes section 366.2(a)(4) and 366.2(d)(1) provisions requiring the Commission to prevent any cost shifting to bundled customers. Such interpretation is also consistent with our prior interpretation.[6]

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[5] See also section 366.2(a)(4) which states "The implementation of a community choice aggregator's program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation."

[6] D.04-12-046 the Commission states:

> All parties agree that AB 117 requires the CCA CRS [Cost Recovery Surcharge] to include a variety of costs incurred on behalf of CCA customers prior to their transferring to the CCA. Such costs include (1)

(footnote continued on next page)

Moreover, subsequent to the passage of AB 117 (section 366.2) the Legislature enacted further statutory provisions expressly prohibiting cost shifting between the bundled service customers and CCA customers.[7] CalCCA's interpretation would have us ignore subsequently issued legislative direction in sections 365.2 and 366.3 which requires us to prevent any cost shifting to bundled service customers and would allow cost shifting to occur.

CalCCA argues that our interpretation is not correct because allowing any costs to be passed to the CCAs by virtue of the no cost shifting requirement would make section 366.2(f) completely ineffectual. CalCCA argument is not correct. Reading section 366.2(f) as the minimum cost that must be recovered does not make such reading ineffectual. It requires us to include these costs in addition to any other costs that would result in cost shifting.

POC contends that section 366.2(c)(5) demonstrates the exclusive nature of the costs listed in section 366.2 because it states that the cost-recovery mechanism is to be imposed pursuant to subdivisions (d), (e) and (f) and these are the subdivision that list

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(footnote continued from previous page)

> costs associated with power contracts and bonds entered into by DWR during the energy crisis; (2) utility power costs, including those of utility retained generation, purchased power and other commitments in approved resource plans; and (3) CTC and historic revenue undercollections and credits applicable to the customer at the time the CCA transferred the customer. (D.04-12-046 at p. 24.)

[7] Specifically, the Legislature enacted sections 365.2 and 366.3 which state:

> The commission shall ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of retail customers of an electrical corporation electing to receive service from other providers. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load. (Pub. Util. Code, § 365.2)

> Bundled retail customers of an electrical corporation shall not experience any cost increase as a result of the implementation of a community choice aggregator program. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load. (Pub. Util. Code, § 366.3)

specific costs. (POC Rehg. App. at p. 12.) However, it is subdivision (d), which states: "It is further the intent of the Legislature to prevent *any* shifting of recoverable costs between customers." (Emphasis added.) If the Legislature had wanted to limit cost shifting to only specifically identified costs, such language would be unnecessary and surplusage and a more limited term rather than "any" would have been used.

CalCCA and POC argue that under the maxim *expressio unius est exclusio alterius* (the expression of one thing implies the exclusion of others) the Commission should have interpreted the list of costs to be exclusive. (CalCCA Rehg. App. at pp. 12-13; POC Rehg. App. at p. 19.) The canons of statutory construction are only a guide and will not be applied if it would defeat legislative intent or produce an absurd result. (*In re J. W.* (2002) 29 Cal.4th 200, 209-210.) Here, limiting costs to only those identified in section 336.2(f) would defeat the legislative intent expressly articulated in the statute and would result in actual cost shifting.

CalCCA and POC contend that the Legislature has, over time, acted to ensure that CCA customers avoid paying for UOG costs and provides a long discussion of various statutory provisions enacted over the past two decades. (CalCCA Rehg. App. at pp. 4-10; POC Rehg. App. at p. 20-22.) However, this discussion does not consider fully the circumstances during that time, and thus, is not determinative.[8]

Both CalCCA and POC argue that cost shifting provisions in sections 366.3(g)[9] and 365.2 are statements of general legislative intent. CalCCA argues that sections 366.2(f) and other provisions are the mechanics for implementing such intent. (CalCCA Rehg. App. at p. 9.) POC cites *State Dept. of Public Health v. Superior Court*

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[8] When the legislature enacted section AB 1890 its purpose was to transition the electric generation market from cost of service-based regulation to a competitive market. In response to the California Energy Crisis, in 2001 the legislature adopted AB 6X, which cancelled the AB 1890 transition of utility generation from regulated to unregulated status and continued Commission regulation of utility owned assets. (D.04-01-026 at p. 4.) When the legislature adopted AB 117 in 2002 authorizing CAA formation, the Commission had not yet addressed the termination of AB 1890 rate freeze and recovery of remaining utility costs which was done in D.04-01-026.

[9] CalCCA mistakenly cites to section 336.3(g). The correct citation is to section 366.3.

(*Dept. of Public Health*) (2015) 60 Cal.4th 940 to advance its position that sections 366.3(g) and 365.2 must be read only as a general provision and not used to repeal the list of specific recoverable costs. However, *Dept. of Public Health* is not on point. In *Dept. of Public Health,* the Court found the two statutes before it impossible to reconcile and was, therefore, required to apply the various doctrines designed to select between conflicting statutes. Here the statutes do not conflict. Our interpretation harmonizes the statutes to avoid conflict. Reading section 366.2(f) as a list of costs that *must* be recovered rather than an exclusive list harmonizes section 366.2(a)(4) and 366.2(d)(1) and subsequently enacted sections 366.3 and 365.2 which require us to prevent any cost shifting.

CalCCA and POC raise issues with the Commission discussion on page 52 of the Decision. (CalCCA Rehg. App at p. 9; POC Rehg. App. at p. 15.) Upon review, we determined that two citations on page 52 of are incorrect. We correct these citations in the ordering paragraphs below. These correct citations clarify any ambiguity that may have existed.

C. Elimination of the ten-year cost recovery limit on post-2002 UOG is lawful and supported by the record.

CalCCA asserts that D.18-10-019 eliminated the ten-year recovery limit on post 2002 UOG without reasonable justification. (CalCCA Rehg. App. at p. 37.) POC and CalCCA further argue that removing the limitation eliminates an obligation we placed on the utilities to manage their portfolio, and thus, allows "avoidable costs" to be recovered from departing load customers. (CalCCA Rehg. App. at p. 37.)

In D.18-10-019 we fully explained our reason for eliminating the 10-year limitation we initially adopted 15 years ago for Edison's Mountainview plant. We reasoned how a ten-year limitation on post-2002 UOG eligibility for the PCIA could result in CCA customers being exempt from paying for a power plant built for their own reliability needs. (D.18-10-019 at pp. 58-59.) We recognized that the cost allocation mechanism that we were establishing had to equitably distribute stranded costs among customers for whom those costs were incurred. (D.18-10-019 at p. 59.) Maintaining the 10-year limitation would not do this. As D.18-10-019 concludes, "[t]here is not justification to continue a 10-year limit on recovering costs for post-2002 UOG from departing load." (D.18-10-019 at p. 157 [Conclusion of Law 13].) Eliminating the 10-year limitation is mandated by the cost shifting provisions in sections 365.2, 366.2(a)(4), 366.2(d) and 366.3.

POC argues that the record does not support the elimination of the ten-year cost recovery limitation for post-2002 UOG. (POC Rehg. App. at p. 22.) POC contends that the Decision ignores evidence that shows this will undermine the Commission's goals in the proceeding. (POC Rehg. App. at p. 23.) POC is not correct. We did not ignore parties' arguments or evidence but rather did not find their arguments or evidence persuasive. What POC is requesting is that we reweigh the evidence. An application for rehearing is not a vehicle for such relitigation. (Cal. Code of Regs., tit. 20, § 16.1, subd. (c); see *OIR re California Renewables Portfolio Standard Program* [D.13-02-037] (2013) at pp. 3-4; see also *Application of Exposition Metro Line Construction Authority for an order authorizing the construction of a two-track at-grade crossing for the Exposition Boulevard Corridor Light Rail Transit line* [D.11-10-022] (2011) at pp. 5-6.)

Finally, POC contends that D.18-10-019 is unlawful because it did not consider whether eliminating the ten-year cost recovery limitation for post-2002 UOG would render the PCIA rate unjust and unreasonable in violation of section 451. (POC Rehg. App. at p. 26.) Sections 365.2, 366.(a)(4), 366.2(d) and 366.3 require us to prevent any cost shifting between bundled service and departing load customers. Eliminating the 10-year cost recovery limitation is necessary to comply with the statutory requirement to eliminate cost shifting and makes it just and reasonable.

D. The Decision lawfully deferred consideration of exempting pre-direct access customers from the PCIA to the ERRA proceedings.

CalCCA contends that D.18-10-019 is unlawful because it fails to address the issue of whether pre-2009 vintage direct access ("DA") customers should be exempt from the PCIA. (CalCCA Rehg. App. at p. 16.) CalCCA contends that this results in the unequal treatment of pre-2009 DA customers and CCA customers, which is not justified. (CalCCA Rehg. App. at p. 17.)

First, D.18-10-019 does not exempt pre-2009 vintage DA customers from PCIA, rather it confirmed that this issue is being handled through other proceedings. Specifically, we stated that there was inadequate information in the record to "disrupt the status quo for pre-2009 Direct Access customers' treatment under the PCIA, and we declined to alter it without prejudice to any decision resolving the issue in A.16-04-018 or other Commission proceedings."[10] (D.18-10-019 at p. 51.) At that time, we were addressing the issue in the utilities' Energy Resource Recovery Accounts ("ERRA") proceedings.

Moreover, CalCCA has not proven discrimination. Pre-2009 vintage departing load customers are not similarly situated to CCA customers as they were the first departing load customers and most UOG resources were not procured on their behalf.[11] (Exhibit AD-1 at pp. 32-33.) We properly deferred the issue to other proceedings currently addressing the issue, where a utility-specific factual record was being developed, and where we could determine whether there are UOG costs that should be included in the PCIA for pre-2009 departing load customers. (See A.16-04-018 et al., Scoping Ruling at p. 3.)

E. The adopted market priced bench market prevents costs shifting and is supported by record evidence.

CalCCA and POC argue that D.18-10-019 is unlawful because it ignores evidence that demonstrates that the value of utility-owned generation and long-term

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[10] PG&E ceased collecting a PCIA from pre-2009 DA customers in 2016 and both SDG&E and Edison had raised the issue of cessation of PCIA obligations for pre-2009 DA customers in their 2016 ERRA forecast applications. There is a factual issue as to whether or what amount of power generating resources are in the pre-2009 vintage. (Exhibit AD-1 at p. 32.)

[11] The first CCA did not begin service until 2010.

contracts have a long-term value that exceeds the price in the short-term market. (CalCCA Rehg. App. at p. 20; POC Rehg. App. at p. 34.) CalCCA and POC contend that this results in cost shifting because it does not reduce the net PCIA portfolio costs by the value of benefits that remain with bundled service customers as statutorily required under section 366.2(g). (CalCCA Rehg. App. at pp. 20-32; POC Rehg. App. at pp. 32-42.)

CalCCA and POC are merely rearguing the issues they raised throughout this proceeding, which have been considered and rejected. As previously discussed, a rehearing application is not a permissible vehicle for a party to relitigate issues determined by us, or to ask us to reweigh the evidence.[12]

The evidence supports the adoption of a benchmark based on actual market transactions. The record supports the determination that it is appropriate to value IOU resources based upon what the market will pay rather than a hypothetical long-term value. With respect to the brown power index, we determined that the Alliance for Retail Energy Markets and the Direct Access Customer Coalition's analysis that the brown power index continued to be reasonable was convincing. (D.18-10-019 at p. 36; Exhibit AD-1 at pp. 8-12.) Based upon the evidence presented, we adopted TURN's proposals for estimating the RPS and RA Adders. (D.18-10-019 at p. 73; Exhibits TURN-01 & TURN-03.) We found this evidence persuasive.

CalCCA and POC contend that the Decision erroneously relies on the Energy Division RA report, which is wrong because it reports prices based on short-term use of a resource to provide RA capacity. (CalCCA Rehg. App. at p. 21; POC Rehg. App at pp. 35-36.) Because there is no error with using short-term values, CalCCA and POC do not allege legal error. CalCCA's and POC's other arguments of alleged flaws with the Energy Division RA Report are merely reargument.

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[12] Pub. Util. Code, § 1732 and Cal. Code Regs., tit. 20, § 16.1(c); see also, e.g. *Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program* [D.13-02-037] (2013) at p. 2.

CalCCA and POC argue that assigning a zero or de minimis value to capacity ignores benefits and results in cost shifting. (CalCCA Rehg. App. at pp. 26-27; POC Rehg. App. at pp. 38-39.) CalCCA and POC argue this ignores the evidence of the value of capacity. Again, this is reargument. We considered the evidence but did not find it convincing. We adopted TURN's approach based upon the evidence and determined it produced as accurate an estimate as possible. (D.18-10-019 at p. 73; Exhibit TURN-1 at 8-10.)

Although we do not agree with parties' arguments of certain alleged benefits, our adopted PCIA methodology, including the true-up mechanism, allows for the capture of benefits. We modify D.18-10-019, as set-forth below, to add a conclusion of law on this issue.

F. The adopted PCIA methodology allows for the exclusion of costs that are determined to be avoidable or not attributed to departing load customers.

CalCCA, POC, and PCE contend that D.18-10-019 is unlawful because it allows cost shifting by including in the PCIA, costs that are not attributable to departing load customers or that are avoidable, in violation of section 366.2(f)(2).[13] (CalCCA Rehg. App. at pp. 32-42; POC Rehg. App. at p. 44; PCE Rehg. App. at p. 1.) CalCCA,

[13] Section 366.2(f)(2) provides:

> (f) A retail end-use customer purchasing electricity from a community choice aggregator pursuant to this section shall reimburse the electrical corporation that previously served the customer for all of the following:
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> (2) Any additional costs of the electrical corporation recoverable in commission-approved rates, equal to the share of the electrical corporation's estimated net unavoidable electricity purchase contract costs attributable to the customer, as determined by the commission, for the period commencing with the customer's purchases of electricity from the community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation.

POC, and PCE argue that the Commission failed to meet the statutory requirement to include only unavoidable costs in the PCIA by rejecting parties' arguments of IOU portfolio mismanagement, and by failing to properly forecast departing load. (CalCCA Rehg. App. at pp. 40; POC Rehg. App. at pp. 43-50; PCE Rehg. App. at pp. 3-15.) CalCCA further asserts the Decision errs by including in the PCIA ongoing capital additions to UOG resources incurred after a load departs. (CalCCA Rehg. App. at pp. 33-34.)

The purpose of this proceeding was to develop a departing load cost recovery *mechanism* that ensures no cost shifting between bundled service and departing load customers. The focus of the proceeding was to determine the categories of costs included in the PCIA, not to look at specific resources within those categories. As the Scoping Memo made clear, this proceeding did "not include revisiting prior Commission determinations regarding the reasonableness of the IOUs' past procurement actions." (Scoping Memo at p. 19.) Prior procurement decisions have already been determined to be reasonable. We properly determined that the issue of whether individual procurement costs should be excluded from the PCIA calculation should be addressed in utility specific proceedings where we can consider facts specific to those resources.[14]

To the extent CalCCA, POC, and PCE are attempting to relitigate their claims that certain categories of portfolio costs are avoidable because the utilities did not properly forecast departing load or did not effectively manage their portfolios in response to departing load, the record evidence rebuts such contentions. These costs were previously approved by us for the benefit of all then bundled service customers and

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[14] For example, in the case of ongoing capital addition costs, we recognized:

> It is possible that new investments in an old power plant may represent such a significant overhaul of the facility as to justify a "re-vintaging" of the facility. Likewise, it is possible that plant investments for certain upgrades may justify a different vintage treatment for those investments than for the underlying facility. But any such analysis must be fact-specific to the plants and spending in question, and is better suited to a GRC evaluating such spending. (D.18-10-019 at p. 135.)

continue to provide reliability benefits. The evidence demonstrated the steps the IOUs have taken to manage their generation portfolios. (Exhibits IOU-1, Ch. 3; IOU-3, Ch. 3.)

CalCCA, POC, and PCE argue that the Decision errs by not making findings of fact or conclusions of law on whether IOU electricity purchase contract costs were avoidable or whether they were attributable to departing load customers. (CalCCA Rehg. App. at pp. 33-34; 43; POC Rehg. App. at p. 43; PCE Rehg. App. at p. 3.) PCE argues the Decision is unlawful because it makes no factual or legal determination that the PCIA will include only legitimate, unavoidable costs and that the utilities have taken all reasonable steps to minimize above market costs. (PCE at p. 2.)

D.18-10-019 determined the specific cost categories of resources to include within the PCIA methodology and did not address specific utility resource decisions. Thus, individual findings of fact or conclusions of law on specific procurement decisions are not appropriate for this proceeding. However, we modify D.18-10-019 as set forth below to add a conclusion of law that clarifies that our PCIA methodology allows us, in utility specific proceedings, to exclude costs we later determine are avoidable or are not attributable to departing load customers.

G. The Commission was not required to address Independent Evaluator and Procurement Review Group reforms in this phase of the proceeding.

POC argues that we abused our discretion and failed to proceed in a manner required by law by failing to make findings of fact and conclusions of law on Independent Evaluator and Procurement Review Group reforms. (POC Rehg. App. at pp. 54-55.) POC contends that we ignored its arguments and testimony on these issues.

Again, POC is merely rearguing evidence submitted in this proceeding in an attempt to achieve a different outcome. Rehearing applications are limited by Section 1732 to specifications of legal error, and POC identifies none.

Moreover, we did not ignore POC's issues. D.18-10-019 summarizes the issues raised in this area by POC[15] and determined that the area of portfolio optimization and cost reduction should be addressed in a second phase. (D.18-10-019, at p. 111.)

POC does not identify any legal authority that requires us to make a finding of fact on every piece of evidence in the record. Rather, section 1705 requires us to make findings of fact on material issues. As the California Supreme Court has explained: "We have never held that an administrative decision must contain a complete summary of all proceedings and evidence leading to the decision. Rather we have repeatedly [Citation] set as our standard a statement which will allow us a meaningful opportunity to ascertain in the principles and facts relied upon by the Commission in reaching its decision." (*Toward Utility Rate Normalization v. Public Utilities Com*. (1978) 22 Cal.3d 529, 540.)

POC does not demonstrate that the Decision's findings or conclusions were inadequate to reasonably apprise the reader of the reasoning behind, and the basis for, our determination. We appropriately found and concluded that we would open a second phase to further develop proposals on portfolio optimization and cost reductions. (D.18-10-019 at pp. 156 & 159 [Finding of Fact 27 & Conclusion of Law 26].) Thus, Independent Evaluator and Procurement Review Group reforms were not a material issue in this proceeding and findings of fact and conclusion of law were not required.

H. The Decision's rejection of a greenhouse gas-free adder is lawful.

CalCCA and POC contend D.18-10-019 violates section 366.2 because it does not establish a premium attributable to greenhouse gas ("GHG") free resources, and thus, results in unlawful cost shifting. (CalCCA Rehg. App. at 28-31; POC Rehg. App. at pp. 40-41.) POC contends the Decision ignores evidence of such unaccounted for value and proceeds to reargue the evidence. (CalCCA Rehg. App. at 28-3; POC Rehg. App. at pp. 40-41.)

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[15] See D.18-10-019 at p. 101.

Again, CalCCA and POC are relitigating this issue and asking us to reweigh the evidence. We have already considered and rejected those factual arguments and reiterating them in this application for rehearing does not establish error. Arguments that the evidence should have been evaluated differently do not demonstrate error.

As testimony explained, "The CAISO energy market prices already include GHG costs and that zero-GHG resources thus already receive additional revenues for the GHGs they avoid." (Exhibit TURN-2 at pp. 11.) Any "market premium attributable to GHG-free resource, will be captured in the adopted true-up." (D.18-10-019 at p. 150.) We considered the evidence and determined that "CalCCA did not demonstrated the need for a separate GHG-free adder" and that CalCCA's approach was "untethered to any reliable, observable market premium." (D.18-10-019 at p. 150.)

CalCCA contends there is no record support for the Decision's conclusion that any market premium attributable to GHG-free resources, to the extent it exists, will be captured in the true-up (CalCCA Rehg. App. at p. 31.) As noted above, testimony supports this conclusion, which is further explained in TURN's briefs. (Exhibit TURN-2 at p. 11; TURN Reply Brief at pp. 7-8.)

CalCCA argues that sections 454.3 and 454.53(a) create a premium for GHG-free resources.[16] (CalCCA Rehg. App. at p. 29-30.) However, nothing in the language of these provisions assures that such renewable resources will receive a premium value.

Finally, CalCCA and POC contend that the Decision fails to comply with section 1705[17] because it does not make findings of fact or conclusions of law on the need for an ancillary service benchmark. Under the law, the Commission is required to make separately stated findings of fact and conclusions of law on all material issues.

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[16] Section 454.3 allows for a rate of return increase for electrical corporations for investments in clean resources and section 454.53(a) declares it State policy that renewable energy and zero-carbon resources supply all retail electricity by the end of 2045.

[17] CalCCA mistakenly sites to section 1701.2(e).

(Pub. Util. Code, § 1705.) CalCCA and POC do not explain or establish this was a material issue for purposes of the Decision.

I. D.18-10-019 does not err in directing parties to focus on cost reduction proposals other than securitization in Phase 2.

CalCCA argues the Decision's failure to direct the utilities to pursue securitization is unlawful because securitization would allow UOG costs to be avoided and section 366(f)(2) permits the allocation of only unavoidable costs.[18] (CalCCA Rehg. App. at p. 35.) CalCCA's argument has no merit. The utilities do not have the authority necessary to implement securitization as enabling legislation is required, and thus, whether any costs are avoidable is speculative at best.

POC argues that D.18-10-019 errs by subordinating securitization to other portfolio optimization and cost reduction proposals in phase 2 of this proceeding. (POC Rehg. App. at pp. 61-63.) POC contends that the Commission abused its discretion because record evidence rebuts the Decision's assumption that securitization of wildfire costs and portfolio costs cannot coexist.

Again, POC is merely rearguing evidence submitted in this proceeding in an attempt to achieve a different outcome and has not identified legal error. Moreover, contrary to POC's claims, D.18-10-019 did not determine that securitization of wildfire costs and portfolio costs could not coexist. Rather, the Decision stated that we were concerned about the feasibility of pursuing securitization given the uncertainties of securitization of wildfire liabilities and the associated implication of such liabilities on overall utility borrowing costs. (D.18.10-109 at p. 114.) Here, we weighed the evidence and determined that it was best for parties to focus their phase 2 efforts on other portfolio management options.

[18] CalCCA states that the decision errs by including the return on equity on UOG assets in PCIA-eligible costs.

J. The PCIA cost cap is lawful.

POC contends that we abused our discretion and committed legal error by creating a cap that does not protect the economic viability of CCAs. (POC Rehg. App. at p. 28.) POC further contends that the Decision's finding that the adopted cap will promote certainty and stability for CCA customers is contradicted by evidence demonstrating that rate escalation will compromise the viability of CCAs. (POC Rehg. App. at p. 28.)

Again, POC is merely rearguing the issues it raised throughout this proceeding, which have been considered and rejected. While we support the creation and development of CCA's, we are statutorily required to ensure there is no cost shifting between the bundled service and departing load customers. The PCIA cost cap ensures compliance with the cost shifting statutory provisions while also providing a level of predictability and certainty to the CCAs. (D.18-10-019 at pp. 85-86.)

POC contends it is unlawful for us to delay implementation of the cost cap to 2020 because it departs from a Commission principle of gradualism, which limits sudden rate increase. (POC Rehg. App. at p. 31.) Generally, we are not bound by prior decisions, especially when circumstances otherwise dictate, and thus, POC has not raised legal error. Moreover, we justified the implementation date. As we explained, because D.18-10-019 corrected outdated and flawed methodology for forecast year 2019, there was an immediate risk of substantial under collection if the cap was not delayed to 2020. (D.18-10-019 at pp. 85-86.) We did not want to start the cap and enable a continual state of under collection in the balancing account.

K. D.18-10-019 does not err in approving the Joint Utilities' revenue allocation factors.

CLECA argues that D.18-10-019 erroneously concludes that the Joint Utilities' proposal contains consistent revenue allocation factors for departing load customers. (CLECA Rehg. App. at pp. 4-6.) CLECA further contends that D.18-10-019 fails to include a finding of fact that the Joint Utilities' proposal would result in consistency. (CLECA Rehg. App. at pp. 4-5.) CLECA argues that the record evidence demonstrates that the allocations factors among the utilities are inconsistent. (CLECA Rehg. App. at p. 6.) CLECA misunderstands the Decision.

In D.18-10-019, we state, "The revenue allocation factors for vintage Indifference Amounts should be consistent with the factors used to allocate generation costs to their bundled service customers." (D.18-10-019, at pp. 124, 157 [Conclusion of Law 15].) Nothing in the text of the Decision or in this Conclusion of Law states that the allocation factors must be consistent among the utilities. Rather we state only that the revenue allocation factors must be consistent with the factors used to allocate generation costs to the utilities' bundled service customers. The Joint Utilities' proposal sought revenue allocation consistency, *within* each utility, between each utilities' departing load and bundled service customers. (Exhibit IOU 01, pp. 4-63, 4-65, n. 93.)

CLECA argues that D.18-10-019 is unlawful because there is no evidence on how the vintage portfolio billing determinants would be calculated and no finding of fact on this issue. (CLECA Rehg. App. at p. 5.) CLECA has not alleged legal error because D.18-10-019 did not authorize vintage billing determinates. We have subsequently addressed this issue in D.19-10-001.

L. There was sufficient notice of this Rulemaking.

CLECA contends that the Commission may not have complied with the notice requirements of section 1711.[19] CLECA states that Commission outreach was limited to sending the press release to a number of local government groups and asking for those groups to disseminate the information to their members. (CLECA Rehg. App.

[19] Section 1711 (a) states in pertinent part:

> Where feasible and appropriate . . . before determining the scope of the proceeding, the commission shall seek the participation of those who are likely to be affected, including those who are likely to benefit from, and those who are potentially subject to, a decision in that proceeding. The commission shall demonstrate its efforts to comply with this section in the text of the initial scoping memo of the proceeding.

at p. 7.) CLECA asserts that it is not clear whether notice reached all customer classes that revenue allocation and rate design may be changed in this proceeding.

CLECA has not alleged legal error as it only speculates that the Commission *may* not have complied with the notice requirements. CLECA cites no evidence that any customer class was affected and did not receive notice. Moreover, in addition to distributing our press release announcing the OII to local government groups, we caused the OII to be served on the service lists for seven Commission Rulemaking proceedings and ten Application proceeding.[20] These proceedings covered a wide range of topics, including rulemakings on residential rate structure, resource adequacy, and renewable portfolio standards, applications for ERRA forecast proceedings, and Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets.

M. Motions for stay and compliance with section 311.5.

POC's Application for Rehearing includes a Motion for Compliance with section 311.5 and a Motion for Stay. POC's request regarding compliance with section 311.5 does not raise legal error with the Decision and is denied. POC's motion for stay is moot with the issuance of this Order.

N. Oral argument is not necessary.

POC requests oral argument pursuant to Rule 16.3. POC contends that the decision departs from long-standing commission precedent, presents issues of exceptional controversy and public importance, and raises questions of first impression.

We have discretion to determine the appropriateness of oral argument in any matter. (See Rule 16.3(a) of the Commission's Rules of Practice and Procedure, Cal. Code of Regs., tit. §20, 16.3, subd. (a).) Rule 16.3 states, in part, that a "request for oral

[20] Rulemaking (R.) 03-10-003; R.05-06-040; R.07-05-025; R.12-06-013; R.14-10-010; R.15-02-020; R.16-02-007; Application (A). 06-03-005; A.14-11-007; A.14-05-024; A.16-04-018; A.16-05-001; A.16-06-003; A.17-04-016; A.17-05-006; A.17-06-005; and A.17-04-018.

argument should explain how oral argument will materially assist the Commission in resolving the application." POC's request states only that oral argument will untangle the issues presented. We are able to determine the issues presented and oral argument will not materially assist us in resolving the application.

III. CONCLUSION

As discussed above, we modify D.18-01-022, as set forth below to make the changes discussed in this Order. Rehearing of D.18-01-022, as modified, is denied, as no legal error has been shown.

THEREFORE, IT IS ORDERED that:

1. D.18-10-019, is modified as follows:

a. Change the second full paragraph on page 76 to read:

> Assembly Bill (AB) 117 (2002 Stats., ch. 838) confers general jurisdiction over CCA program implementation to the Commission and requires the Commission to take certain actions to protect utility bundled customers and departing load customer and to assure reasonable service to CCAs. (D.05-12-041 at p. 3.)
>
> Section 701 provides us sufficient jurisdiction to require the contract information in exercising our regulatory oversight. Requiring ESPs to provide contract information is cognate and germane to utility regulation as it specifically relates to our statutory duty to ensure that there is no cost shifting between bundled retail customers of the electrical corporations and bundled retail customers who elect to receive service from other providers. (Pub. Util. Code §§ 365.2 & 366.3.)

b. On page 76, third full paragraph, first sentence, change the phase "In addition to that comprehensive jurisdiction" to "In addition to our jurisdiction under 701"

c. Change the first and second full sentences on page 52 to read:

> That position would read Public Utilities Code Sections 365.2 and 366.3[105] out of the law.[106] Such a reading of Section 366.2(f) would also render the statute inconsistent with its own subdivision (a)(4),

> thus violating the "cardinal rule of statutory construction that . . . a statute must be read and considered as a whole, in order that the true legislative intention may be determined."[107]

c. Add Conclusion of Law 26:

> The adopted PCIA methodology and annual true up will provide departing load customers with a fair and equitable share of benefits that remain with the bundled service customer to the extent benefits are determined by the Commission to exist.

d. Add Conclusion of Law 27:

> The adopted PCIA methodology and annual true up, will allow the Commission, in utility specific proceedings, to exclude costs determined to be unreasonable because they are avoidable or not attributable to departing load customers.

2. Rehearing of D.18-10-019, as modified, is denied.

3. This proceeding, Rulemaking (R.) 17-06-026 remains open.

This order is effective today.

Dated January 16, 2020, at San Francisco, California.

MARYBEL BATJER
President
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
Commissioners